COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM MASSPOWER
D. T. E. 05-27

Date: July 10, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

MP 1-24 Please provide the cost of the original Main and services installed to serve Masspower and the original incremental rate calculation associated with providing service to the MASSPOWER plant.

Response: See Bay State's response to MP-1-30 for the original costs of the Utility Plant associated with the 16" Line to serve MassPower.

The Company has been unable to gain possession of the original incremental rate calculation associated with providing service to the MASSPOWER plant. However, in referring to the Department order in D.P.U. 89-217, at 8, based on the Company's estimated cost to build the line and including operating and maintenance costs, Bay State's annual revenue requirement would be $1.64 million over a 20-year period. Also at page 8, the Department's discussion indicates that based on this annual revenue requirement the minimum monthly demand rate for transportation service would be $2.73 per MMBtu.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM UWUA LOCAL 273
D. T. E. 05-27

Date: July 10, 2005

Responsible: Stephen H. Bryant, President

UWUA-1-5 Please provide copies of all documents, communications, press releases and other written materials that Bay State or NiSource have provided to investors, investor analysts, board members or the press regarding changes in staffing levels since September 1, 1998 and the present date.

Response: The Company does not have specific documents, communications, press releases, etc. to investors, investor analysts, board member or the press that specifically refer to staffing levels. However, the Company provides below a list of the requested materials that include references to staffing levels as well as overall strategic Company direction which may impact staffing levels.

The Company is preparing these bulk documents and will supplement this response with the attachments as soon as they are available.

See Attachment UWUA -1-5 (A) for NiSource Annual Reports from 1999 to 2004.

See Attachment UWUA – 1-5 (B) for NiSource Fact Sheets from first quarter 2003, to first quarter 2005.

See Attachment UWUA – 1-5 (C) for NiSource 2004 Statistical Summary.

See Attachment UWUA – 1-5 (D) for NiSource Analyst Presentations from February 2003 to February 2005.

See Bulk Response to AG-1-10 for NiSource Analyst Presentations from March 2000 to November 2000, which has been included for your convenience.

The Company has also provided numerous financial reports and other information in response to AG – 1-2, which was a bulk response. Please see the listing of available documents and notify the Company if any additional material is requested, which will be provided upon request.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM UWUA LOCAL 273
D. T. E. 05-27

Date: July 9, 2005

Responsible: Danny G. Cote, General Manager

UWUA-1-7 (a) Please provide an organizational chart that includes all of Bay State's employees, and all such changes to that organizational chart, for the period September 1, 1997 to date. If there are different organizational charts for different purposes, such as organizational charts for the three geographic divisions in Massachusetts and separate charts for "physical" versus office/clerical workers regardless of region, please provide all such charts.

(b) Please provide a current organizational chart that shows all NiSource operating companies, affiliates, and subsidiaries.

Response: (a) Please see Attachment UWUA-1-7 for current Company organizational chart. The Company is unable to locate organizational charts for prior periods, however, refer to response UWUA-1-6 regarding historical organizational changes.

(b) Please see response AG-1-98, Attachment AG-1-98 (b) for the organization structure by NiSource operating companies, affiliates, and subsidiaries.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM LOCAL UWUA 273
D. T. E. 05-27

Date: July 9, 2005

Responsible: Stephen H. Bryant, President
Danny G. Cote, General Manager

UWUA-1-18 (a) For the period since the announcement of Bay State's merger with NiSource, please provide any and all documents, memos or e-mails from NiSource to Bay State providing guidance, advice, instructions or directions regarding the hiring of staff, staffing levels, or rates of compensation.

(b) For the period since the announcement of Bay State's merger with NiSource, please provide any and all documents, memos or e-mails from NiSource to Bay State providing guidance, advice, instructions or directions regarding the level of expenditures on O & M and capital expenditures, or the need to effect economies in these expenditures, or requests to control these expenditures.

Response:

(a) Please see Bay State's response to UWUA-2-8 for NiSource's role in providing guidance, advice, instructions or directions regarding the hiring of staff, staffing levels, or rates of compensation. The Company is unable to locate e-mails specifically related to staffing levels, however, please see Attachment UWUA-1-18 (a) for NiSource's 2004 and 2005 performance adjustment recommendations directive. Similar directives are not available prior to 2004. See also Mr. Barkauskas' testimony Exh. BSG/SAB-1.

(b) The Company develops its O&M and Capital budgets based on the needs of each department or location. Spending levels can be highly influenced by outside forces such as customer needs, municipal projects, state construction projects and corrosion on pipes. Historical and current year spending levels plus capital needs for any additional major Growth Betterment or Replacement projects are considered when developing future period budgets. NiSource approves or revises, if appropriate, the O&M and capital budgets. The Company's "Capital Authorization Handbook", Attachment UWUA-1-18 (b), encompasses NiSource's guidance, advice, instructions and directions relating to capital expenditures.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM UWUA LOCAL 273
D. T. E. 05-27

Date: July 10, 2005

Responsible: Stephen H. Bryant, President

UWUA-2-9 Please provide copies of all documents that define or describe the relationship between or among Bay State, NiSource Corporate Services and NiSource in terms of which entity sets or changes Bay State's staffing levels, working conditions of Bay State's employees, or terms of compensation and benefits.

Response: See Exhibit BSG/SAB-1 – Please see Mr. Barkauskas' testimony for the Company's position on compensation and benefits. Other related materials can be found in the following list of exhibits:

See Exhibit BSG/SAB-2 (A) - agreement between Bay State Gas and USWA Clerical/Technical – Springfield Division

See Exhibit BSG/SAB-2 (B) - agreement between Bay State Gas and USWA – Springfield Division

See Exhibit BSG/SAB-2 (C) for agreement between Bay State Gas and UWUA Clerical/Technical – Brockton Division

See Exhibit BSG/SAB-2 (D) for agreement between Bay State Gas and UWUA – Brockton Division

See Exhibit BSG/SAB-2 (E) for agreement between Bay State Gas and IBEW – Northampton Division

See Exhibit BSG/SAB-2 (F) for agreement between Bay State Gas and IBEW – Lawrence Division

The Company also addresses staffing, compensation and benefit issue in the following responses to information requests:

Response to DTE – 18-1

Response to UWUA – 1-1

Response to UWUA – 1-2

Response to UWUA – 2-8

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM UWUA LOCAL 273
D. T. E. 05-27

Date: July 10, 2005

Responsible: Stephen H. Bryant, President

BULK ATTACHMENT

UWUA-2-30 Please provide a copy of the decisions, orders or settlement agreements from Maine and New Hampshire referenced in Mr. Bryant's testimony and that approved or allowed a mechanism for recovering the costs of the main replacement programs in those states, or that reflected an agreement to consider such a mechanism.

Response: Attachment UWUA-02-30 (a) is a copy of Settlement Agreement dated June 9, 1992 between Northern Utilities and the New Hampshire Public Utilities Commission. See page 2 for a discussion of the step rate adjustment related to Northern's bare steel replacement program.

Attachment UWUA-02-30 (b) is a copy of the Order in Docket DR 91-081 that approved the above-mentioned settlement.

Attachment UWUA-02-30 (c) is a copy of the Maine Public Utility Commission Order Approving Stipulation regarding the accelerated replacement of cast iron facilities. The Stipulation is attached to the Order.

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

NORTHERN UTILITIES, INC.	)	DOCKET NO. DR 91-081

Settlement Agreement

This Agreement is entered into this 9th day of June, 1992, by and among Northern Utilities, Inc. ("Northern" or "the Company") and the Staff of the Public Utilities Commission (the "Staff" and the "Commission" respectively) with the intent of resolving the issues discussed herein. Further, it is the desire of the Company and Staff in executing this Agreement to expedite the Commission's consideration and resolution of the issues which are the subject of this Agreement.

ARTICLE I

Introduction

On July 18, 1991, Northern, pursuant to RSA 378:3, filed revised tariff pages designed to increase annual revenues by $2,547,517. The proposed tariffs were to be effective on August 19, 1991.

On July 18, 1991, Northern also filed, pursuant to Section RSA 378:27, a petition for a temporary rate increase of $1,900,000 for service rendered on or after August 19, 1991.

On August 6, 1991, the Commission entered an Order of Notice setting a hearing on August 26, 1991, to address the level of temporary rates and a prehearing conference on the issue of permanent rates. The Company duly noticed the hearings in accordance with the Commission's Order of Notice. On August 12, 1991, in Order No. 20,207, the Commission, pursuant to RSA 378:6, suspended the effective date of the permanent rate tariffs.

On August 26, 1991, a hearing was held regarding the above-mentioned issues. The Company, the Staff and the Consumer Advocate entered appearances. Testimony was presented by Northern and the Staff in support of the temporary rates. In Report and Supplemental Order No. 20,256, dated September 30, 1991, the Commission authorized the Company to implement a temporary rate increase at an annual level of $1,900,000 effective for service rendered on or after September 30, 1991.

Staff conducted a field audit between October 1991 and January 1992 with respect to the Company's request for permanent rate relief, including numerous discovery requests to which the Company responded. In March 1992, the Staff presented prefiled testimony and exhibits stating its position on the cost of service, step adjustments, weather normalization, cost of capital, marginal cost methodology, class revenue allocation, and rate design. Northern filed rebuttal testimony on April 23 and April 28, and certain Staff members and the Consumer Advocate submitted surrebuttal testimony on or before May 12, 1992.

Following extensive discussions the Staff and Northern reached agreement on the issues in this proceeding as set forth below. This Agreement provides for a permanent increase of $1,318,714 effective for meters read on and after the date of the Commission's order approving permanent rates, implementation of step adjustments effective November 1, 1992, and annually until the agreed bare steel replacement program is completed, and a reconciliation and refund as described below.

ARTICLE II

Revenue Deficiency

The Company's original testimony and exhibits proposed an increase in annual revenues of $2,547,517. The Staff's testimony and exhibits recommended an increase of $285,023. The parties have agreed that it is just and reasonable to approve a permanent increase of $1,318,714. A computation of Staff's calculation of this Revenue Deficiency is attached to this Agreement as Attachments 1, 2, and 3. Northern does not concur with the components of that calculation, but does agree to the total stipulated Revenue Deficiency.

ARTICLE III

Step Adjustment

The parties agree that to implement the bare steel replacement program it is reasonable to authorize the Company to implement step adjustments in base rates to be effective for meter readings on or after November 1, 1992, and annually until the agreed bare steel replacement program is completed, which would provide for recovery of:

1. The return and related income taxes on (a) additional investments for the period April 1, 1991 through September 30, 1992, as shown on Schedule NU-1A-1 and (b) additional non-revenue producing investments related to the bare steel replacement program on an annual basis until such time as the program is completed and subject to audit prior to implementation. The amount of the step adjustment would be calculated using the actual capital expenditures during the above periods, and a pre-tax rate of return of 13.19%, and reflecting cost of service principles, as demonstrated in proposed Schedule NU-1-5;

2. Annualized depreciation expense on the actual plant additions referenced in paragraph 1 above based on depreciation rates resulting from the audit and review

referred to in paragraph 3 below, and the associated rate of return impact of deferred income taxes on the actual plant additions referenced in paragraph 1 from the previous annual adjustment using a pre-tax rate of return of 13.19%, in accordance with established regulatory principles of the Commission;

3. The difference between the pro formed test year depreciation expense for services proposed by Northern and the depreciation expense for services recommended by Staff, subject to audit and review by the Commission prior to September 30, 1992. All other categories of depreciation will be established based upon the rates in Table 1 of Schedule NU-4-1;

4. Annualized amounts for incremental property taxes and O&M expenses (savings) related to the plant used to service the Newington electric generation facility owned by Public Service Company of New Hampshire;

5. The return and related income taxes, depreciation and deferred tax impact on $269,242 in rate base reflecting capital investments used to serve Domtar Gypsum, Inc. ("Domtar") as proposed in Company Exhibit NU-3, p. 16, using the same calculations as in paragraphs 1 and 2 above;

6. The Staff reserves the right to recommend at any time after implementation of the initial step adjustment on November 1, 1992 that base rate treatment of bare steel investments be accomplished through a general rate case as opposed to step adjustments.

The step adjustments will be reduced by an amount equal to pro forma net revenues from Domtar calculated as follows:

> (Actual historical firm volumes for twelve-month period ending September 30, 1992 and succeeding twelve-month periods) times (the non-gas portion of the rates to serve Domtar as approved pursuant to the tariffs attached to this Agreement) less ($41,393 test year net transportation revenues for Domtar built into base rates).

ARTICLE IV

Rate Design

In regard to rate design, the Parties agree that:

1. The rates set forth on Attachment 4 to this Agreement are just and reasonable and are designed to recover the revenue requirement as set forth on Attachment 5;

2. The class allocations underlying the rates reflect marginal cost principles in conjunction with rate continuity considerations;

3. The step adjustments provided for in Article III of this Agreement will be collected using class allocations and rates which reflect marginal cost principles in conjunction with continuity considerations which could consist of equal percentage adjustments to all components;

4. In the next base rate case filed by the Company the proposed rates will be designed using the class allocation methodology approved by the Commission in EnergyNorth Natural Gas, Inc., DR 90-183, and that Staff shall support such allocation method. In the event that such allocation methodology is not decided in DR 90-183, then the parties will be free to present and support any allocation method;

5. The rate continuity considerations used to design the rates set forth on Attachment 4 to this Agreement shall be used by the Company in its next base rate case and such considerations shall be supported by Staff in that case;

6. The cost of gas included in the summer base rates set forth on Attachment 4 is $ 3846 per therm and in the winter base rates is $ 3318 per therm;

7. The minimum bill provisions for the LV-1 rate have been retained as shown on Attachment 4, but such minimum bill provisions will not be used in the rates proposed by the Company in the next base rate case and Staff shall support the exclusion of the minimum bill provisions in the next case;

8. The residential non-heating class be added with rates distinct from those applying to the residential heating class;

9. Given that the rates set forth in Attachment 4 reflect marginal cost principles and that the utilization of pipeline capacity for the benefit of the summer period customers is also considered, the Parties agree, after FERC Order 636 is implemented, to examine the possibility of revising the cost of gas adjustment clause formula to re-assign a portion of pipeline demand charges to the winter period gas costs;

10. A discounted rate should be available to low income residential customers and that the discount should be 15% off the general residential rates, or at whatever level of discount the Commission deems appropriate, provided, however, that if any different subsidy level is adopted, the rates set forth in Attachment 4 must be adjusted so as to recover the subsidy from all other rate classes;

11. The Parties agree that it is appropriate to modify the methodology for calculating marginal costs, as set forth in the Report of the Gas Rate Design Investigation, DE 86-208, to recognize that mains extension costs are a component of marginal distribution capacity costs; and

12. Salem Division propane customers will be billed according to the general rates set forth on Attachment 4 but will be billed a specific cost of gas adjustment factor reflecting the applicable gas costs.

The Parties did not reach an agreement as to either the proper method to calculate marginal production capacity costs or whether bad debts should be reflected in marginal commodity costs. It is necessary to resolve both of these issues for future marginal and avoided cost calculations and the parties have agreed to use Northern's C&LM proceeding, DR 92-048, for that purpose. However, sufficient information was available to design the rates set forth on Attachment 4 according to marginal cost principles.

ARTICLE V

Refund Rate

The Parties agree that the Company will be required to refund an amount pursuant to the temporary rate period. The parties did not reach agreement on the specific calculation of the amount to be refunded pursuant to the temporary rate period, and have agreed to request a hearing before the Commission to present their respective positions and ask the Commission to render a decision on this one issue. The Staff's and Company's proposed calculations are attached as Attachments 6 and 7, respectively.

The parties agree that the refund should be reduced by an amount equal to the reduction in non-gas revenues through September 30, 1992, which will result from the Company's implementation of seasonal rates, when compared to the non-gas revenues that would have resulted from applying the temporary rates, adjusted for the stipulated increase, from the end of the temporary rate period until September 30, 1992.

ARTICLE VI

Environmental Remediation

The stipulated revenue deficiency provides for the amortization over a ten-year period of the environmental remediation costs incurred through the end of the test year with the unamortized balance included in rate base. The parties further agree that in regard to environmental remediation costs subsequent to the end of the test year, the Company should make a formal request to the Commission for deferral accounting treatment as a regulatory asset. Such request shall include a detailed explanation and accounting of all such costs.

ARTICLE VII

Post-Retirement Benefits Other Than Pension

The parties agree that to the extent the Commission recognizes, in any other proceeding or otherwise, the impacts of FASB Statement 106 regarding post-retirement benefits other than pension, revenue to recover such expenses may be included in the Step Adjustments described in Article III.

ARTICLE VIII

Exhibits

The parties agree to enter into the record, as Exhibits, all prefiled testimony and data responses for purpose of showing the original positions of the parties.

ARTICLE IX

Conditions

The making of this Agreement shall not be deemed in any respect to constitute an admission by any party that any allegation or contention in these proceedings is true or valid.

This Agreement is expressly conditioned upon the Commission's acceptance of all of its provisions, without change or condition, except as indicated in Articles IV and V, and if the Commission does not accept it in its entirety, without change or condition, the Agreement shall be deemed to be null and void and without effect, and shall not constitute any part of the record in this proceeding nor be used for any other purpose.

The Commission's acceptance of this Agreement does not constitute continuing approval of or precedent regarding any particular issue in this proceeding, except as provided for in the calculation of Step Adjustments in Article III, and the provisions of Article IV, paragraphs 4 and 10, but such acceptance does constitute a determination that (as the parties believe) the base rates increased to yield the revenue contemplated by this Agreement will be just and reasonable.

The discussions which have produced this Agreement have been conducted on the explicit understanding that all offers of settlement and discussions relating thereto are and shall be privileged, and shall be without prejudice to the position of any party or participant representing any such offer or participating in any such discussion, and are not to be used in any manner in connection with this proceeding, any future proceeding or otherwise.

IN WITNESS WHEREOF, the parties have caused this Agreement to be duly executed in their respective names by their agents, each being fully authorized to do so on behalf of their principal.

Northern Utilities, Inc.

Dated: June 9, 1992

Scott J. Mueller, Counsel

Staff of Public Utilities Commission

Dated: June 9, 1992

Eugene F. Sullivan, III

1183r

Settlement Agreement
DR 91-081
Attachment 1

CFP NORTHERN UTILITIES DR 91-081
5/7/92 REVENUE REQUIREMENT ATTACHMENT 1

RATE BASE	23,553,791
COST OF CAPITAL	10.01%
REQUIRE NET OPERATING INCOME	2,357,899
ADJUSTED NET OPERATING INCOME	1,485,428
DEFICIENCY	872,471
TAX EFFECT (34%)	449,455
REQUIRED INCREASE	1,321,926
BI-MONTHLY BILLING *	(3,212)
REQUIRED INCREASE *	1,318,714

* REQUIRES COMMISSION APPROVAL

Settlement Agreement
DR 91-081
Attachment 2

SPP
5/7/92

NORTHERN UTILITIES INC
RATE BASE
FOR THE TWELVE MONTHS ENDED
MARCH 31, 1991

DR 91-081
ATTACHMENT 2

	13 MONTH AVERAGE	COMPANY PROFORMA ADJUSTMENT	RATE BASE	SETTLEMENT ADJUSTMENTS	RATE BASE
GAS PLANT IN SERVICE	27,310,279	4,105,240	31,415,519	(2,072,144)	29,343,375
LESS: C W I P	0		0		0
TOTAL PLANT IN SERVICE	27,310,279	4,105,240	31,415,519	(2,072,144)	29,343,375
LESS: ACCUMULATED DEPRECIATION	5,666,904	241,241	5,908,145	0	5,908,145
CONTRIBUTION IN AID OF CONST	0		0		0
NET PLANT IN SERVICE	21,643,375	3,863,999	25,507,374	(2,072,144)	23,435,230
CASH WORKING CAPITAL	1,060,907	13,737	1,074,644	(28,440)	1,046,204
ADD: MATERIALS & SUPPLIES	326,572		326,572		326,572
PREPAYMENTS	35,243		35,243		35,243
UNAMORTIZED MERGER COSTS	43,378		43,378		43,378
SOUTHERN NH GAS ACQUISITION	55,069		55,069		55,069
ENVIRONMENTAL REMEDIATION	146,408		146,408		146,408
LESS: CUSTOMER DEPOSITS	(243,351)		(243,351)		(243,351)
INTEREST ON CUSTOMER DEPOSITS	(15,087)		(15,087)		(15,087)
DEFERRED FEDERAL INCOME TAX	(941,157)	122,417	(818,740)		(818,740)
ACCRUED PROPERTY TAXES	(1,292)		(1,292)		(1,292)
ACCRUED FRANCHISE TAX	(57,719)		(57,719)		(57,719)
REIMBURSABLE CONTRIBUTIONS	(233,714)		(233,714)		(233,714)
PENSION & BENEFITS RESERVES				(164,410)	(164,410)
TOTAL WORKING CAPITAL	175,257	136,154	311,411	(192,850)	118,561
RATE BASE	21,818,631	4,000,153	25,818,785	(2,264,994)	23,553,791

Settlement Agreement
DR 91-081
Attachment 3

SFP
5/7/92

NORTHERN UTILITIES
OPERATING INCOME STATEMENT
TWELVE MONTHS ENDED
SOURCE: NU-3-2

DR 91-081
ATTACHMENT 3

	12 MONTHS ENDED MAR 31, 1991	COMPANY ADJUSTMENTS	TEST YEAR AS PROFORMED BY COMPANY	SETTLEMENT ADJUSTMENTS	TEST YEAR
OPERATING REVENUES					
REVENUES- FIRM	18,246,635	472,413	18,719,048	(174,720)	18,544,318
REVENUES- INTERRUPTIBLE	3,516,100		3,516,100		3,516,100
REVENUES- OTHER	331,232	(41,393)	289,839		289,839
TOTAL REVENUES	22,093,967	431,020	22,524,987	(174,730)	22,350,257
OPERATING EXPENSES					
COST OF GAS - FIRM	11,048,213	(210,458)	10,837,755		10,837,755
OST OF GAS - INTERRUPTIBLE	3,516,100		3,516,100		3,516,100
OTHER PRODUCTION	124,000	720	124,720	(757)	123,963
DISTRIBUTION	1,627,080	36,531	1,663,611	(135,554)	1,528,057
CUSTOMER ACCOUNTING	1,009,758	(2,221)	1,007,537	(16,358)	991,179
SALES & NEW BUSINESS	461,020	(103,405)	357,615	(57,841)	299,774
ADMINISTRATIVE & GENERAL	1,466,646	236,415	1,703,061	(20,144)	1,682,917
INTEREST ON CUSTOMER DEPOSITS	23,241	(443)	22,798		22,798
TAXES:					
FEDERAL INCOME TAX	(20,536)	71,984	51,448	173,216	224,664
PROPERTY AND PAYROLL	435,739	(16,801)	418,938		418,938
STATE	211,096		211,096		211,096
OTHER	159,735	9,907	169,642	(11,724)	157,918
DEPRECIATION	1,105,860	102,702	1,208,562	(226,929)	981,633
AMORTIZATION	6,107	35,066	41,173	(44,135)	(2,962)
TOTAL REVENUE DEDUCTIONS	21,174,059	159,997	21,334,056	(340,226)	20,993,830
OPERATING RENTS NET	109,778		109,778	19,223	129,001
NET GAS OPERATING INCOME	1,029,686	271,023	1,300,709	184,720	1,485,428

Settlement Agreement
DR 91-081
Attachment 4

Attachment 4
Page 1

NORTHERN UTILITIES, INC.
Rate Summary

Description	Residential								Commercial and Industrial									
	Regular				Low Income													
	Heat R-5		Non-Heat R-6		Heat R-10		Non-Heat R-11		General G-1		Air Conditioning AC-1		Heat GH-1		Large Volume LV-1		Extra Large Volume XLV-1	
Final Rate Design																		
Customer		$6.50		$6.50		$5.53		$5.53		$12.00		$10.00		$12.00		$50.00		$57.17
Head Block - Winter	First 75	$0.7159	First 15	$0.7394	First 75	$0.6085	First 15	$0.6285	First 350	$0.6711	First 225	$0.6264	First 750	$0.6399	First 1350	$785.18	All Therms	$0.5167
Tail Block - Winter	Over 75	$0.6547	Over 15	$0.6796	Over 75	$0.5564	Over 15	$0.5777	Over 350	$0.6103	Over 225	$0.5006	Over 750	$0.5599	Over 1350	$0.5816		
Head Block - Summer	First 25	$0.5391	First 10	$0.5202	First 25	$0.4582	First 10	$0.4421	First 275	$0.5126	First 225	$0.4151	First 525	$0.5036	First 1350	$589.95	All Therms	$0.3728
Tail Block - Summer	Over 25	$0.4969	Over 10	$0.5018	Over 25	$0.4223	Over 10	$0.4265	Over 275	$0.4675	Over 225	$0.3828	Over 525	$0.4321	Over 1350	$0.4370		
Revenue Proof		$7,529,972		$341,431		$58,825		$574		$812,907		$80,551		$10,336,772		$2,344,783		
Increase		$629,666		$30,958		$759		$42		$16,074		($4,180)		$588,349		$52,608		
		9.1%		10.0%		1.3%		7.8%		2.0%		-4.9%		6.0%		2.3%		

Attachment 4
Page 2

Northern Utilities, Inc.
Cost Study Summaries

	Residential			Commercial and Industrial					Company
	Heating	Non-Heat	Total	General G-1	Heating GH-1	Air Cond AC-1	Large Vol LV-1	Total C&I	Total
Revenue and Cost Data									
Proforma TY Rev	$6,958,372	$311,005		$796,833	$9,748,423	$84,731	$2,292,175	$12,922,162	$20,191,539
% of total	34.5%	1.5%	36.0%	3.9%	48.3%	0.4%	11.4%	64.0%	100.0%
Staff Marginal Cost	$7,626,129	$469,274		$610,911	$9,460,504	$38,409	$1,839,598	$11,949,422	$20,044,825
% of total	38.0%	2.3%	40.4%	3.0%	47.2%	0.2%	9.2%	59.6%	100.0%
Company Marginal Cost	$10,290,071	$697,259	$10,987,330	$783,812	$12,036,852	$42,232	$2,233,839	$15,096,735	$26,084,065
% of total	39.4%	2.7%	42.1%	3.0%	46.1%	0.2%	8.6%	57.9%	100.0%
Company Allocated Cost	$8,491,434	$566,279	$9,057,713	$711,758	$10,428,138	$51,960	$1,980,869	$13,172,725	$22,230,438
% of total	38.2%	2.5%	40.7%	3.2%	46.9%	0.2%	8.9%	59.3%	100.0%
Marginal Cost Study Statistics									
Maximum	39.4%	2.7%	42.1%	3.0%	47.2%	0.2%	9.2%	59.6%	100.0%
Minimum	38.0%	2.3%	40.4%	3.0%	46.1%	0.2%	8.6%	57.9%	100.0%
Average	38.7%	2.5%	41.3%	3.0%	46.7%	0.2%	8.9%	58.7%	100.0%
Revenue Target Calculations									
Avg % vs. TY %	4.3%	1.0%	5.3%	-0.9%	-1.6%	-0.2%	-2.5%	-5.3%	0.0%
Res Shares change by 20% Change in Share	0.9%	0.2%		-0.2%	-0.3%	-0.0%	-0.5%	-1.1%	
Revised Share	35.3%	1.7%	37.1%	3.8%	48.0%	0.4%	10.9%	62.9%	
Preliminary Revenue Target	$7,595,666	$372,836		$809,131	$10,313,830	$79,800	$2,334,654	$13,537,415	$21,505,917
	109.2%	119.9%		101.5%	105.8%	94.2%	101.9%	104.8%	106.5%
The lesser of Preliminary revenue Target or Target Capped at 10% Increase									
Revised Prelim Rev Target	$7,595,666	$342,106		$809,131	$10,313,830	$79,800	$2,334,654	$13,537,415	$21,475,187
% Increase	109.2%	110.0%		101.5%	105.8%	94.2%	101.9%	104.8%	
Resulting Shortfall									$30,730
Difference of 10% Cap and Preliminary Rev Req Increase	0.8%	0.0%		8.5%	4.2%	15.8%	8.1%	5.2%	
Difference Weighted by TY Rev	58,543	0		67,385	409,435	13,404	186,739	676,963	735,506
Weighted Difference as % of Total	8.0%			9.2%	55.7%	1.8%	25.4%	92.0%	100.0%
Revenue Shortfall Allocated by Wghtd Diff %	$2,446	$0		$2,815	$17,107	$560	$7,802	$28,284	$30,730
Final Revenue Target	$7,598,112	$342,106		$811,946	$10,330,937	$80,360	$2,342,456	$13,565,700	$21,505,917
	109.2%	110.0%		101.9%	106.0%	94.8%	102.2%	105.0%	106.5%

Attachment 4
Page 3

Northern Utilities
Residential Subsidy

	Heat				Non-Heat				Total Subsidy
	Regular Rates	Subsidized Rates	Billing Determnts	Subsidy	Regular Rates	Subsidized Rates	Billing Determnts	Subsidy	
Customer	$6.50	$5.53	998	$973	$6.50	$5.53	39	$38	$1,011
First Block Rate- Winter	$0.7159	$0.6085	39,400	$4,231	$0.7394	$0.6285	243	$27	$4,258
Second Block Rate- Winter	$0.6546	$0.5564	37,946	$3,726	$0.6796	$0.5777	112	$11	$3,737
First Block Rate- Summer	$0.5390	$0.4582	10,025	$811	$0.5202	$0.4421	196	$15	$826
Second Block Rate- Summ	$0.4968	$0.4223	8,597	$641	$0.5018	$0.4265	127	$10	$650
				$10,381				$101	$10,482

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NORTHERN UTILITIES, INC.
Rate Design Worksheet

Line No.	Description	Residential: Total: Heat (Block)	Residential: Total: Heat	Residential: Total: Non-heat (Block)	Residential: Total: Non-heat	Residential: Regular: Heat R-5 (Block)	Residential: Regular: Heat R-5	Residential: Regular: Non-Heat R-6 (Block)	Residential: Regular: Non-Heat R-6	Residential: Low Income: Heat R-10 (Block)	Residential: Low Income: Heat R-10	Residential: Low Income: Non-Heat R-11 (Block)	Residential: Low Income: Non-Heat R-11	Commercial and Industrial: General G-1 (Block)	Commercial and Industrial: General G-1	Commercial and Industrial: Air Conditioning AC-1 (Block)	Commercial and Industrial: Air Conditioning AC-1	Commercial and Industrial: Heat GH-1 (Block)	Commercial and Industrial: Heat GH-1	Commercial and Industrial: Large Volume LV-1 (Block)	Commercial and Industrial: Large Volume LV-1	COMPANY TOTAL
1	Rate Design Notes																					
2	Customer Charge		$6.50		$6.50										$12.00		$10.00		$12.00		$50.00	
3	Minimum Tail Block Rate																					
4	Winter		$0.2700		$0.2950										$0.2250		$0.1150		$0.1750		$0.1974	
5	Summer		$0.1650		$0.1700										$0.1350		$0.0500		$0.1000		$0.1051	
6	Head Block Revenues collected In:																					
7	Winter		85.0%		81.5%										60.0%		8.0%		80.0%		60.0%	
8	Summer		15.0%		18.5%										40.0%		92.0%		20.0%		40.0%	
9	REFERENCE DATA																					
10	Test Year Pro Forma Revenues		6,958,372		311,005		6,900,306		310,473		58,066		532		796,833		84,731		9,748,423		2,292,175	20,191,539
11	Embedded Gas Rate Per Therm																					
12	Winter		$0.3846		$0.3846		$0.3846		$0.3846		$0.3846		$0.3846		$0.3846		$0.3846		$0.3846		$0.3846	
13	Summer		$0.3318		$0.3318		$0.3318		$0.3318		$0.3318		$0.3318		$0.3318		$0.3318		$0.3318		$0.3318	
14																						
15																						
16	FINAL REV REQ		7,598,112		342,106										811,946		80,360		10,330,937		2,342,456	21,505,917
17																						
18	MARGINAL COSTS																					
19	Customer Cost				$31.66										$37.62		$23.02		$43.56		$294.80	
20	Winter Therm Charge				$0.7120										$0.6519		$0.7034		$0.7102		$0.6804	
21	Summer Therm Charge				$0.1942										$0.1939		$0.1937		$0.1941		$0.1939	
22														Block		Block		Block		Block		
23	BILLING DETERMINANTS													Size		Size		Size		Size		
24	Number of Annual Bills		124,172		19,694		123,174		19,655		998		39		6,554		169		44,340		176	91,586
25	Total Winter Therms		8,353,556		185,620		8,276,564		185,266		76,992		354		697,000		4,770		13,507,270		2,752,740	17,409,658
26	Total Summer Therms		2,017,780		159,610		1,999,158		159,287		18,622		323		590,160		190,610		3,649,520		1,674,430	6,442,239
27	First Block Therms-- Winter	75	4,444,450	15	107,024	75	4,405,050	15	106,781	75	39,400	15	243	350	325,267	225	2,234	750	6,645,584	1,350	122,282	
28	Second Block Therms-- Winter	9,157	3,909,460	327	78,596	9,157	3,871,515	327	78,484	9,157	37,946	327	112	13,572	371,733	1,056	2,536	76,710	6,861,686	177,679	2,630,458	
29	Third Block Therms-- Winter	9,157	0	327	0	9,157	0	327	0	9,157	0	327	0		0	1,056	0		0		(0)	
30	TOTAL WINTER		8,353,910		185,620		8,276,564		185,265		77,346		355		697,000		4,770		13,507,270		2,752,740	
31																						
32	First Block Therms-- Summer	25	1,138,416	10	79,151	25	1,128,391	10	78,955	25	10,025	10	196	275	291,964	225	100,088	525	1,859,260	1,350	106,712	
33	Second Block Therms-- Summer	4,655	879,364	428	80,459	4,655	870,767	428	80,332	4,655	8,597	428	127	12,381	298,196	2,120	90,522	52,298	1,790,260	84,159	1,567,718	
34	Third Block Therms-- Summer	4,655	0	428	0	4,655	0	428	0	4,655	0	428	0		0		0		0		0	
35	TOTAL SUMMER		2,017,780		159,610		1,999,158		159,287		18,622		323		590,160		190,610		3,649,520		1,674,430	0
36																						
37	RATE DESIGN																					
38																						
39	Preliminary Rates																					
40	Set Customer Charge		$6.50		$6.50										$12.00		$10.00		$12.00		$50.00	
41	Commod @ Min Tail Block + Gas Rate																					
42	Winter		$0.6546		$0.6796										$0.6096		$0.4996		$0.5596		$0.5820	
43	Summer		$0.4968		$0.5018										$0.4668		$0.3818		$0.4318		$0.4369	
44	Revenues generated		7,277,789		334,251										779,026		76,848		9,666,611		2,342,453	
45	Remaining revenues		320,323		7,855										32,920		3,512		664,326		3	
46	Winter Head Block Revenues		$272,275		$6,402										$19,752		$281		$531,461		$2	
47	Summer Head Block Revenues		48,048		1,453										13,168		3,231		132,865		1	
48	Winter Head Block		$0.0613		$0.0598										$0.0607		$0.1258		$0.0800		$0.0000	
49	Summer Head Block		$0.0422		$0.0184										$0.0451		$0.0323		$0.0715		$0.0000	
50																						

Attachment 4, Page 5

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NORTHERN UTILITIES, INC.
Rate Design Worksheet

Line No.	Description	Residential Total Heat	Residential Total Non-heat	Regular Heat R-5		Regular Non-Heat R-6		Low Income Heat R-10		Low Income Non-Heat R-11		Commercial and Industrial General G-1		Air Conditioning AC-1		Heat GH-1		Large Volume LV-1		COMPANY TOTAL
51	Rates, Prior to Alloc of Res Sub.																			
52	Customer	$6.50	$6.50		$6.50		$6.50		$5.53		$5.53		$12.00		$10.00		$12.00		$50.00	
53	First Block Rate -- Winter	$0.7159	$0.7394		$0.7159		$0.7394		$0.6085		$0.6285	Fst 350	$0.6703	Fst 225	$0.6254	Fst 750	$0.6396	Fst 1350	$784.37	
54	Second Block Rate -- Winter	$0.6546	$0.6796		$0.6546		$0.6796		$0.5564		$0.5777	Nxt 1322	$0.6096	Nxt 831	$0.4996	Nxt 7596	$0.5596	Nxt 17632	$0.5810	
55	Third Block Rate -- Winter	$0.6546	$0.6796		$0.6546		$0.6796		$0.5564		$0.5777	Ovr 1357	$0.6096	Ovr 1056	$0.4996	Ovr 7671	$0.5596	Ovr 17767	$0.5810	
56																				
57	First Block Rate -- Summer	$0.5390	$0.5202		$0.5390		$0.5202		$0.4582		$0.4421	Fst 275	$0.5119	Fst 225	$0.4141	Fst 525	$0.5033	Fst 1350	$589.14	
58	Second Block Rate -- Summer	$0.4968	$0.5018		$0.4968		$0.5018		$0.4223		$0.4265	Nxt 1210	$0.4668	Nxt 1895	$0.3818	Nxt 5177	$0.4318	Nxt 82809	$0.4364	
59	Third Block Rate -- Summer	$0.4968	$0.5018		$0.4968		$0.5018		$0.4223		$0.4265	Ovr 1238	$0.4668	Ovr 2120	$0.3818	Ovr 5226	$0.4318	Ovr 84159	$0.4364	
60																				
61	Rev Proof	7,598,344	342,106		7,529,138		341,431		58,825		574		811,946		80,360		10,330,937		2,342,117	21,505,810
62																				
63	Residential Subsidy								10,381		101									10,482
64																				
65	Subsidy Weighting Factors				8.0%		0.0%						9.2%		1.8%		55.7%		25.4%	
66																				
67	Allocated Subsidy				834		0						960		191		5,835		2,661	10,482
68																				
69																				
70	Residential Sub Surcharge per Therm				$0.0001		$0.0000						$0.0007		$0.0010		$0.0003		$0.0006	
71	(Res Heat Reduced by Sub Res Heat)																			
72																				
73	Final Rate Design																			
74	Customer				$6.50		$6.50		$5.53		$5.53		$12.00		$10.00		$12.00		$50.00	
75	First Block Rate -- Winter			Fst 75	$0.7159	Fst 15	$0.7394	Fst 75	$0.6085	Fst 15	$0.6285	Fst 350	$0.6711	Fst 225	$0.6264	Fst 750	$0.6399	Fst 1350	$785.18	
76	Second Block Rate -- Winter			Nxt 9082	$0.6547	Nxt 31	$0.6796	Nxt 9082	$0.5564	Nxt 312	$0.5777	Nxt 1322	$0.6103	Nxt 831	$0.5006	Nxt 7596	$0.5599	Nxt 17632	$0.5816	
77	Third Block Rate -- Winter			Ovr 9157	$0.6547	Ovr 32	$0.6796	Ovr 9157	$0.5564	Ovr 327	$0.5777	Ovr 1357	$0.6103	Ovr 1056	$0.5006	Ovr 7671	$0.5599	Ovr 17767	$0.5816	
78																				
79	First Block Rate -- Summer			Fst 25	$0.5391	Fst 10	$0.5202	Fst 25	$0.4582	Fst 10	$0.4421	Fst 275	$0.5126	Fst 225	$0.4151	Fst 525	$0.5036	Fst 1350	$589.95	
80	Second Block Rate -- Summer			Nxt 4630	$0.4969	Nxt 41	$0.5018	Nxt 4630	$0.4223	Nxt 418	$0.4265	Nxt 1210	$0.4675	Nxt 1895	$0.3828	Nxt 5177	$0.4321	Nxt 82809	$0.4370	
81	Third Block Rate -- Summer			Ovr 4655	$0.4969	Ovr 42	$0.5018	Ovr 4655	$0.4223	Ovr 428	$0.4265	Ovr 1238	$0.4675	Ovr 2120	$0.3828	Ovr 5226	$0.4321	Ovr 84159	$0.4370	
82																				
83	Revenue Proof				7,529,972		341,431		58,825		574		812,907		80,551		10,336,772		2,344,783	21,505,815
84																				
85																				
86	Increase				629,666		30,958		759		42		16,074		(4,180)		588,349		52,608	1,314,276
87	% Increase				9.1%		10.0%		1.3%		7.8%		2.0%		-4.9%		6.0%		2.3%	6.5%
88																				
89																				
90	Revenues by Season																			
91	Winter				6,088,687		196,172		47,845		325		484,487		3,514		8,360,763		1,603,373	16,785,167
92	Summer				1,441,285		145,259		10,980		248		328,419		77,037		1,976,009		741,410	4,720,648
93					7,529,972		341,431		58,825		574		812,907		80,551		10,336,772		2,344,783	21,505,815
94	Gas Revenues																			
95	Winter				3,183,167		71,253		29,611		136		268,066		1,835		5,194,896		1,058,704	9,807,6[illegible]
96	Summer				663,321		52,851		6,179		107		195,815		63,244		1,210,911		555,576	2,748,0[illegible]
97	Total				3,846,487		124,105		35,790		243		463,881		65,079		6,405,807		1,614,280	12,555,6[illegible]
98																				
99	Net Revenues																			
100	Winter				2,905,521		124,919		18,233		189		216,421		1,679		3,165,867		544,669	6,977,4[illegible]
101	Summer				777,964		92,407		4,802		141		132,604		13,793		765,098		185,834	1,972,[illegible]
102	Total				3,683,485		217,326		23,035		330		349,025		15,472		3,930,966		730,504	8,95[illegible]
	Ratio of Summer Tail to:																			
	Winter Head	1.44	1.47		1.44		1.47		1.44		1.47		1.44		1.64		1.48		1796.75	
	Winter Tail	1.32	1.35		1.32		1.35		1.32		1.35		1.31		1.31		1.30		1.33	

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Bay State Gas Company
D.T.E. 05-27
Attachment UWUA-02-30 (a)
Page 25 of 51

Settlement Agreement
DR 91-081
Attachment 5

Attachment 5

Northern Utilities, Inc.
Development of Settlement Sales Service Revenue Requirement

Non-Gas Revenue Requirement

		Actual	Company Adjustment	Staff Adjustment	Final Adjusted	
1	Firm Revenues	$18,246,635			$18,246,635	Schedule NU-3-2 Page 1
2	Gas Costs	$11,048,213			$11,048,213	Schedule NU-3-2 Page 1
3	Non-Gas Revenues	$7,198,422			$7,198,422	
4	Weather Adjustment		$390,419	$84,453	$474,872	
5	Salem		$1,479		$1,479	
6	Accounting Adjustment		($37,927)		($37,927)	Schedule NU-6-12
					$438,424	
8	Revenue Deficiency				$1,318,714	
9	Non-Gas Rev Req				$8,955,560	
	Revised Gas Costs				$12,550,357	Rev Wp NU-6-12, pages 13, 18
	Sales service Rev Req				$21,505,917	
					106.5%	

Settlement Agreement
DR 91-081
Attachment 6

ATTACHMENT 6

STAFF'S POSITION ON TEMPORARY RATE REFUND

On July 18, 1991 Northern petitioned the commission for a temporary base rate increase of $1,900,000 annually. The increase comprised $1,561,532 to existing firm customers and $338,468 of projected revenue from a new customer (Domtar Inc.) served under a proposed new rate schedule. Staff supported the Company in its request. On September 30, 1991 the commission issued an order approving a temporary increase of $1,900,000.

As a result of the commission's September 30 decision, the firm rates currently in effect will bring in an additional $1,900,000 annually if the sales projections underlying the rates prove to be correct. Should the sales projections understate actual sales then the additional revenue received by the Company will exceed $1,900,000. Thus, the refund to ratepayers should be based on the difference between the revenues actually received during the temporary rate period and the revenue that would have been received had the rates to existing customers been set to recover the agreed permanent increase of $1,318,714 (see Article 2 to Settlement Agreement). Staff contends that the exclusion of Domtar firm revenues from the agreement on the permanent rate increase has no bearing on the commission's refund decision.

In the negotiations which led to the agreed permanent rate increase, staff, as a negotiating concession to the Company, agreed to exclude the sales and revenue associated with the provision of firm service to Domtar. At no time did staff agree that the concession would also apply to the determination of the temporary rate refund.

CALCULATION OF REFUND

1.	Temporary Rate Increase		$1,900,000
2.	Agreed Permanent Rate Increase		$1,318,714
3.	Annualized Refund Amount		$581,286
4.	Normalized Test Year Sales, including Company projection for Domtar		$34,164,210
5.	Refund per Therm		$0.01701
6.	Temporary Rate Period Sales, including Domtar		Y
7.	Refund	Y x	$0.01701

3673561
347507
326,054

Settlement Agreement
DR 91-081
Attachment 7

Schedule 1

Northern Utilities, Inc.
Calculation of Refund, Excluding Rate XLV

Line No	Description		Notes
1	Temporary Increase	$1,900,000	
2	Portion of Temporary Increase designed for Domtar	$338,468	September 30, 1991 letter to W. Amold, Attachment 3
3	Remainder to be collected from all Other Classes	$1,561,532	Line 1 – Line 2
4	Settlement Deficiency	$1,318,714	
5	Annualized refund amount, excluding Domtar	$242,818	Line 3 – Line 4
6	Annual Staff normalized therm sales	33,766,210	Exhibit SWH 4 plus 195,380 therms (Rate AC–1)
7	Refund per Annualized Therms	$0.0072	Line 5 / Line 6
8	Temporary Rate Period Sales, excluding Domtar	32,735,298	Schedule 2
9	Refund, excluding Domtar	$235,405	Line 7 x line 8

Schedule 2

Northern Utilities, Inc.
Temporary Rate Period Sales

	Actual							Forecast		Temporary Rate Period Sales
	Oct (1)	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	
Total Firm MMBtu Sales	236,684	308,016	474,020	593,915	630,890	569,676	437,935	275,896	182,261	3,709,293
Domtar Sales	66,056	43,898	40,151	47,666	57,333	56,896	51,763	32,000	40,000	435,763
Firm sales, excluding Domtar	170,628	264,118	433,869	546,249	573,557	512,780	386,172	243,896	142,261	3,273,530

(1) Prorated, see Schedule 6
(2) Temporary Rate Period sales will be updated after the completion of the Temporary rate period.

Northern Utilities, Inc.
Rate XLV Permanent Rates

Schedule 3

Line No	Description		Notes
1	Temporary Sales Net Revenues	$9,098,422	September 30, 1991 letter to W. Amold, Attachment 1
2	Permanent Net Revenues	$8,517,136	Line 2 – $1,900,000 + $1,318,714
3	Permanent Rates as a % of Temporary Net Revenues	93.6%	Line 2 / Line 1
	XLV Temporary Net Revenue Rates		
4	Customer	$61.07	September 30, 1991 letter to W. Amold, Attachment 3, Line 17
5	Winter	$0.1411	September 30, 1991 letter to W. Amold, Attachment 3, Line 18
6	Summer	$0.0438	September 30, 1991 letter to W. Amold, Attachment 3, Line 19
	XLV Permanent Net Revenue Rates		
7	Customer	$57.17	Line 4 x Line 3
8	Winter	$0.1321	Line 5 x Line 3
9	Summer	$0.0410	Line 6 x Line 3
	Difference		
10	Customer	$3.90	Line 4 – line 7
11	Winter	$0.0090	Line 5 – line 8
12	Summer	$0.0028	Line 6 – line 9

Note: This schedule shows XLV Permanent rates proposed by the Company which are subject to change in negotiation with Parties and are also subject to Commission approval.

Northern Utilities, Inc.
Calculation of Rate XLV Refund

Schedule 4

	Domtar Billing Determinants, Temporary Rate Period		
1	Customer Count	9	
2	Summer Period Sales	1,380,561	Schedule 2
3	Winter Period sales	2,977,070	Schedule 2
	Refund		
4	Customer Count	$35.12	Schedule 3, Line 10 x Line 1
5	Summer Period Sales	$3,863	Schedule 3, Line 11 x Line 2
6	Winter Period Sales	$26,837	Schedule 3, Line 12 x Line 3
7	Total	$30,736	

Note: This schedule reflects XLV Permanent rates proposed by the Company which are subject to change in negotiation with Parties and are also subject to Commission approval.

Northern Utilities, Inc.
Refund Summary

Schedule 5

XLV Refund	$30,736
Refund Excluding XLV	$235,405
Total	$266,140

Schedule 6

Northern Utilities, Inc.
Calculation of October Sales in Temporary Rate Period

	Total	Rate XLV	Total, Net of XLV
Billing month Sales	251,952	66,056	185,896
% of Sales after 9/30	93.94%	100.00%	
Sales after 9/30	236,684	66,056	170,628

Northern Utilities, Inc.

September 30, 1991

Wynn E. Arnold, Esquire
Executive Director and Secretary
New Hampshire Public Utilities Commission
8 Old Suncook Road, Building 1
Concord, New Hampshire 03301

RE: Northern Utilities, Inc. - Proposed Temporary Rate Increase
Docket No. DR 91-081

Dear Mr. Arnold:

Enclosed for filing are ten copies of revised schedules that Northern Utilities has prepared to calculate the temporary rate levels. The purpose of this further revision to the temporary rate calculation schedules that were submitted by letter dated September 20 is to exclude the proforma adjustment to test year sales, but to include the proforma adjustment in determining the revenue collections during the period of temporary rates.

Very truly yours,

James D. Simpson

James D. Simpson
Director of Rates

enclosures
cc: D.A. Deans
J.A. Ferro
T.W. Sherman
P.R. Moul
M.J. Morganti
J.L. Harrison
E. Robinson
R.P. Cencini
Audrey A. Zibelman, Esquire
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Connie Fillion
Paul B. Dexter, Esquire

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NORTHERN UTILITIES, INC.
CALCULATION OF TEMPORARY RATE ADJUSTMENT
ALL RATE SCHEDULES EXCLUDING RATE XLV

Line No.	DESCRIPTION	TOTAL	GAS COST	NET REVENUE
1	Test Year Revenues	18,246,635	11,048,213	7,198,422
2	Temporary Rate Increase	1,900,000		1,900,000
3	Revenues including Temporary Rate Increase	20,146,635	11,048,213	9,098,422
4				
5	Non Gas Revenues from Rate XLV (Attachment 3)			338,468
6				
7	Total Temporary Revenues excluding Rate XLV	19,808,167	11,048,213	8,759,954
8	(line 3 – line 5)			
9				
10	Temporary Revenues to Remaining Classes	108.56%		
11	as a % of Test Year Revenues			
12	(line 10 / line 1)			
13				

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Attachment 2

NORTHERN UTILITIES, INC.
CALCULATION OF TEMPORARY RATES:
ALL RATE SCHEDULES EXCLUDING RATE XLV

Line No.	DESCRIPTION	<------- RESIDENTIAL	R-1	R-85 (Low Inc) ------->	Comm & Indust G-1		Air Condition AC-1	Commercial Heat GH-1		Large Volume LV-1		Salem Propane Rate C&I	
	Determination of Temporary Rates												
1	Current Rates												
2	Customer Charge		4.50	3.50		8.00	8.00		8.00	1,350	1055.05	5	5.00
3	First Block	10	0.8648	0.7923	30	0.8797		10	0.8455			5	1.0000
4	Second Block	140	0.7633	0.6997	120	0.7582		40	0.7303			50	0.6200
5	Third Block				150	0.7314						90	0.5200
6	Fourth Block											150	0.4200
7	Last Block	>150	0.6982	0.6933	>300	0.7047	0.6166	>50	0.6901	>1350	0.6682	>300	0.3900
8													
9	Current Rates Adj for Average TY Gas Costs												
10	Customer Charge		4.50	3.50		8.00	8.00		8.00	1,350	826.86	5	6.22
11	First Block	10	0.6958	0.6233	30	0.7107		10	0.6765			5	1.2434
12	Second Block	140	0.5943	0.5307	120	0.5892		40	0.5613			50	0.8634
13	Third Block				150	0.5624						90	0.7634
14	Fourth Block											150	0.6634
15	Last Block	>150	0.5292	0.5243	>300	0.5357	0.4476	>50	0.5211	>1350	0.4992	>300	0.6334
16													
17	Temporary Rates *												
18	Customer Charge		4.89	3.80		8.68	8.68		8.68	1,350	897.62	5	6.75
19	First Block	10	0.7553	0.6766	30	0.7715		10	0.7344			5	1.3498
20	Second Block	140	0.6451	0.5761	120	0.6396		40	0.6093			50	0.9373
21	Third Block				150	0.6105						90	0.8287
	Fourth Block											150	0.7202
	Last Block	>150	0.5745	0.5691	>300	0.5815	0.4859	>50	0.5657	>1350	0.5419	>300	0.6876

* Temporary Rates = Current Rate adjusted for Average Test Year Gas Costs *1.0856

NORTHERN UTILITIES, INC.
CALCULATION OF TEMPORARY RATES:
Rate XLV

Line No.	Description	
1	Permanent Revenues	23,661,532
2	Proposed Gas Revenues	13,232,824
3	Proposed Net Revenues	10,428,708
4	Temporary Revenues	20,146,635
5	Proposed Gas Revenues	11,048,213
6	Proposed Net Revenues	9,098,422
7	Temporary Revenues as a % of Permanent Net Revenues	87.244%
8	Permanent XLV Rates	
9	Customer Charge	$70.00
10	Winter Rate	$0.5493
11	Summer Rate	$0.3207
12	Permanent Net Revenue Rates XLV Rate	
13	Customer Charge	$70.00
14	Winter Rate	$0.1617
15	Summer Rate	$0.0502
16	Temporary Net Revenue Rates	
17	Customer Charge	$61.07
18	Winter Rate	$0.1411
19	Summer Rate	$0.0438
20	Temporary Total Revenue Rates (with $.3521 of Gas Cost rolled in)	
21	Customer Charge	$61.07
22	Winter Rate	$0.4931
23	Summer Rate	$0.3959
24	Temporary Total Revenues	
25	Customer Charge	$732.85
26	Winter	$828,477
27	Summer	$910,487
28	Total	$1,739,697
29	Temporary Gas Revenues	$1,401,229
30	Temporary Non-Gas Revenues	$338,468

Calculation of Average Cost of Gas in Test Year

	TOTAL	NATURAL GAS	PROPANE
Income Statement Firm Cost of Gas	11,048,213	10,964,259	83,954
Schedule 15 Calendar Month Sales		31,142,490	170,150
Average Cost of Gas in the Test Year		0.3521	0.4934

REVISED

Settlement Agreement
DR 91-081
Attachment 7

Entered as Exhibit
at June 11, 1992
Hearing

Revised June 10, 1992

Schedule 1

Northern Utilities, Inc.
Calculation of Refund, Excluding Rate XLV

Line No	Description		Notes
1	Temporary Increase	$1,900,000	
2	Portion of Temporary Increase designed for Domtar	$338,468	September 30, 1991 letter to W. Amold, Attachment 3
3	Remainder to be collected from all Other Classes	$1,561,532	Line 1 – Line 2
4	Settlement Deficiency	$1,318,714	
5	Annualized refund amount, excluding Domtar	$242,818	Line 3 – Line 4
6	Annual Staff normalized therm sales	33,766,210	Exhibit SWH 4 plus 195,380 therms (Rate AC–1)
7	Refund per Annualized Therms	$0.0072	Line 5 / Line 6
8	Temporary Rate Period Sales, excluding Domtar	32,792,306	Schedule 2
9	Refund, excluding Domtar	$235,815	Line 7 x line 8

Revised June 10, 1992

Schedule 2

Northern Utilities, Inc.
Temporary Rate Period Sales

	Actual							Forecast		Temporary Rate Period Sales
	Oct (1)	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	
Total Firm MMBtu Sales	236,935	308,564	474,970	595,157	632,117	570,776	437,935	276,091	182,449	3,714,994
Domtar Sales	66,056	43,898	40,151	47,666	57,333	56,896	51,763	32,000	40,000	435,763
Firm sales, excluding Domtar	170,878	264,666	434,819	547,491	574,784	513,880	386,172	244,091	142,449	3,279,231

(1) Prorated, see Schedule 6
(2) Temporary Rate Period sales will be updated after the completion of the Temporary rate period.

Revised June 10, 1992

Northern Utilities, Inc.
Rate XLV Permanent Rates

Schedule 3

Line No	Description		Notes
1	Temporary Sales Net Revenues	$9,098,422	September 30, 1991 letter to W. Amold, Attachment 1
2	Permanent Net Revenues	$8,517,136	Line 1 – $1,900,000 + $1,318,714
3	Permanent Rates as a % of Temporary Net Revenues	93.6%	Line 2 / Line 1
	XLV Temporary Net Revenue Rates		
4	Customer	$61.07	September 30, 1991 letter to W. Amold, Attachment 3, Line 17
5	Winter	$0.1411	September 30, 1991 letter to W. Amold, Attachment 3, Line 18
6	Summer	$0.0438	September 30, 1991 letter to W. Amold, Attachment 3, Line 19
	XLV Permanent Net Revenue Rates		
7	Customer	$57.17	Line 4 x Line 3
8	Winter	$0.1321	Line 5 x Line 3
9	Summer	$0.0410	Line 6 x Line 3
	Difference		
10	Customer	$3.90	Line 4 – line 7
11	Winter	$0.0090	Line 5 – line 8
12	Summer	$0.0028	Line 6 – line 9

Note: This schedule shows XLV Permanent rates proposed by the Company which are subject to change in negotiation with Parties and are also subject to Commission approval.

Revised June 10, 1992

Northern Utilities, Inc.
Calculation of Rate XLV Refund

Schedule 4

	Domtar Billing Determinants, Temporary Rate Period		
1	Customer Count	9	
2	Summer Period Sales	1,380,561	Schedule 2
3	Winter Period sales	2,977,070	Schedule 2
	Refund		
4	Customer Count	$35.12	Schedule 3, Line 10 x Line 1
5	Summer Period Sales	$3,863	Schedule 3, Line 11 x Line 2
6	Winter Period Sales	$26,837	Schedule 3, Line 12 x Line 3
7	Total	$30,736	

Note: This schedule reflects XLV Permanent rates proposed by the Company which are subject to change in negotiation with Parties and are also subject to Commission approval.

Revised June 10, 1992

Northern Utilities, Inc.
Refund Summary

Schedule 5

XLV Refund	$30,736
Refund Excluding XLV	$235,815
Total	$266,550

Schedule 6

Northern Utilities, Inc.
Calculation of October Sales in Temporary Rate Period

	Total	Rate XLV	Total, Net of XLV
Billing month Sales	252,219	66,056	186,163
% of Sales after 9/30	93.94%	100.00%	
Sales after 9/30	236,935	66,056	170,878

Northern Utilities, Inc.

September 30, 1991

Wynn E. Arnold, Esquire
Executive Director and Secretary
New Hampshire Public Utilities Commission
8 Old Suncook Road, Building 1
Concord, New Hampshire 03301

RE: Northern Utilities, Inc. - Proposed Temporary Rate Increase
Docket No. DR 91-081

Dear Mr. Arnold:

Enclosed for filing are ten copies of revised schedules that Northern Utilities has prepared to calculate the temporary rate levels. The purpose of this further revision to the temporary rate calculation schedules that were submitted by letter dated September 20 is to exclude the proforma adjustment to test year sales, but to include the proforma adjustment in determining the revenue collections during the period of temporary rates.

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Attachment

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NORTHERN UTILITIES, INC.
CALCULATION OF TEMPORARY RATE ADJUSTMENT
ALL RATE SCHEDULES EXCLUDING RATE XLV

Line No.	DESCRIPTION	TOTAL	GAS COST	NET REVENUE
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8	(line 3 – line 5)			
9				
10	Temporary Revenues to Remaining Classes	108.56%		
11	as a % of Test Year Revenues			
12	(line 10 / line 1)			
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Attachment 2

NORTHERN UTILITIES, INC.
CALCULATION OF TEMPORARY RATES:
ALL RATE SCHEDULES EXCLUDING RATE XLV

Line No.	DESCRIPTION	<------- RESIDENTIAL -------	R-1	R-65 (Low Inc)	Comm & Indust G-1		Air Condition AC-1	Commercial Heat GH-1		Large Volume LV-1		Salem Propane Rate C&I	
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* Temporary Rates = Current Rate adjusted for Average Test Year Gas Costs *1.0856

NORTHERN UTILITIES, INC.
CALCULATION OF TEMPORARY RATES:
Rate XLV

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11	Summer Rate	$0.3207
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	TOTAL	NATURAL GAS	PROPANE
Income Statement Firm Cost of Gas	11,048,213	10,964,259	83,954
Schedule 15 Calendar Month Sales		31,142,490	170,150
Average Cost of Gas in the Test Year		0.3521	0.4934

DR 91-081

NORTHERN UTILITIES, INC.

Report and Order Approving the Settlement Agreement on Permanent Rates and Adopting a Method to Calculate the Temporary Rate Refund.

..OO..

Appearances: LeBoeuf, Lamb, Leiby & MacRae by Paul K. Connolly, Jr., Esq. and Scott J. Mueller, Esq. on behalf of Northern Utilities, Inc.; for the Consumer Advocate, Michael W. Holmes, Esq.; and for the Public Utilities Commission, Eugene F. Sullivan, III, Esq.

REPORT

I. Procedural History

On July 18, 1991, Northern Utilities, Inc. (Northern or Company) filed, pursuant to RSA 378:3, revised tariff pages designed to produce a permanent increase in annual revenues of 11.5% or $2,547,517. On the same day, Northern also filed a petition for a temporary increase in annual revenues of $1,900,000.

On August 6, 1991, the commission issued an Order of Notice setting a hearing on August 26, 1991 to address the level of temporary rates and to develop a procedural schedule for permanent rates. The Company duly noticed the hearing in accordance with the commission's Order of Notice. On August 12, 1991, in Order No. 20,207, the commission, pursuant to RSA 378:6, suspended the effective date of the permanent rate tariffs.

On August 26, 1991, a hearing was held regarding the above-mentioned issues. Testimony was presented by Northern and Staff in support of the requested increase. In Report and Supplemental Order No. 20,256, dated September 30, 1991, the commission authorized the Company to implement a temporary rate increase at an annual level of $1,900,000, effective for service rendered on or after September 30, 1991.

Staff conducted a field audit between October 1991 and January 1992, and in March 1992 presented prefiled testimony and exhibits on issues relating to the requested permanent rate increase. Northern filed rebuttal testimony on April 23 and 28, and certain Staff members and the Office of the Consumer Advocate (OCA) submitted surrebuttal testimony on or before May 12, 1992.

Following extensive discussions, Staff and Northern reached agreement on all issues relating to the determination of permanent rates. The OCA declined to be a party to the agreement. The fundamental aspects of the settlement agreement, which was submitted June 10, 1992, are the recommendations to: (a) increase permanent revenues by $1,318,714, effective the date of the commission's permanent rate order, and (b) implement step adjustments to permanent rates on November 1, 1992 and annually thereafter until Northern's bare steel replacement program is completed. Attachments 1, 2, and 3 to the settlement agreement are sponsored by Staff and provide computational support for the agreed permanent rate increase. Northern does not concur with the components of that calculation, but does agree that the total stipulated increase is just and reasonable.

Further, because the agreed permanent rate increase is less than the approved temporary rate increase, the Staff and the Company agree that a refund is necessary but do not agree on how the amount to be refunded should be calculated. On June 11, 1992, a hearing was held to present the above mentioned settlement agreement and to hear testimony on the sole contested issue of the refund amount for the temporary rate period. On June 19, 1992, the Staff and the Company submitted briefs on the contested issue, and on June 30, 1992, Northern submitted its reply brief. The OCA concurs with Staff's refund position.

II. Settlement Agreement

Revenue Deficiency

The Company's original testimony and exhibits proposed an increase in annual revenues of $2,547,517. Staff's testimony and exhibits supported a permanent increase of $285,023. The parties to the settlement agreed to a permanent increase of $1,318,714. As shown in Attachment 1 to the agreement, the agreed increase is consistent with a rate base of $23,553,791, a cost of capital of 10.01% and a net operating income of $1,485,428.

Rate Base

The agreed rate base of $23,553,791 reflects settlement adjustments totalling $2,264,994. The largest adjustments relate to the removal of plant additions made after the test year (including non-revenue producing bare steel investments) and a $269,242 investment related to the provision of firm service to Domtar Gypsum, Inc. (Domtar).

Cost of Capital

The Company's proposed base rate increase reflected a weighted cost of capital of 11.55%, incorporating a 13.95% cost of equity. Those rates were subsequently revised in rebuttal testimony to 11.09% and 13.15% respectively. Staff witness Coleman initially recommended 9.49% and 11.11%, but revised those rates on surrebuttal to 9.58% and 10.64%. The parties to the settlement agreed to a weighted cost of 10.01%

Net Operating Income

The agreed net operating income for the test year represents a net $184,720 increase over the Company proformed figure of $1,300,709. Included in that adjustment is a reduction in revenues to reflect the removal of Domtar from the revenue deficiency calculation, and a reduction in depreciation expense pending the outcome of a Staff audit relating to the method of accounting for service investments. Any revision to net operating income resulting from that audit will be incorporated in the first step adjustment.

Step Adjustments

In order to implement the bare steel replacement program that the Company designed in conjunction with the Commission's Engineering Department, the parties to the settlement agreed to recommend implementation of step adjustments in base rates starting November 1, 1992 and annually thereafter until the program is completed. The purpose of the replacement program is to ensure safe and adequate service to customers of Northern. Among other things, the step adjustments would provide for recovery of the depreciation and return on non-revenue producing investments related to the bare steel program, and the depreciation and return on $269,242 of capital investments used to serve Domtar. Among other things, the size of the step adjustments will be reduced by an amount equal to the net revenues[1] received from the sale of firm gas to Domtar.

Testimony was presented by Company witness Sherman that about $5.7 million of non-revenue producing assets will be added to rate base between the end of the test year and September 30, 1992. The depreciation and return on those investments less the Domtar net revenues is expected to produce a first year step adjustment of approximately $500,000.

Gas Safety Engineer, Richard Marini, testified that Northern's distribution system consisted of a large amount of bare steel which was installed prior to federal regulations barring its use in 1960. The bare steel is subject to corrosion and Northern has completed a study showing a pattern of leaks in areas where bare steel is concentrated. Mr. Marini testified that the replacement of the bare steel would take years and a substantial investment by the Company. He, therefore, recommended the use of annual step adjustments to ensure the bare steel was replaced promptly and to reduce the regulatory expense of annual rate increase requests.

Weather Normalization

Staff and the Company submitted weather normalizing adjustments to test year revenues. While both parties employed the same general method to calculate their adjustments, they differed

[1] i.e., base rates less gas costs.

on the sample size utilized to determine the mean or "normal" degree days. The Company chose a sample of 20 years, whereas Staff used 30 years of data. As a result, the Company proposed a weather normalizing adjustment of $390,419 and the Staff $474,554. The settlement agreement reflects Staff's adjustment.

Rate Design

(a) Marginal Cost Based Rate Design

The marginal cost studies submitted in this case are the product of a methodology approved by the commission in 1988 following several years of discussion and debate among representatives of Staff, the OCA and the two largest gas companies in the State. Those studies show that the test year revenues generated by residential heating and non-heating customers fell substantially short of the costs to serve those customers. Those shortfalls were made up, in part, by subsidies from commercial and industrial customers.

The marginal cost studies also showed that the costs of connecting new customers to the system, regardless of class, are much greater than current levels of customer charges, and that the cost of supplying gas in the winter months is significantly greater than the supply cost in summer months. In addition, the studies pointed out the need to differentiate in the ratemaking process between residential heating and non-heating customers.

In light of these results, and consistent with recent decisions by the commission in support of marginal cost based rate design, Staff and the Company agreed to make certain structural changes in rates in order to better reflect marginal operating costs. Among other things, the parties to the settlement agreed: (a) to use marginal cost principles in conjunction with rate continuity considerations to determine class revenue allocations; (b) that the Company would use in its next base rate case the class allocation methodology approved in EnergyNorth Natural Gas, Inc., DR 90-183; (c) that the rate continuity considerations used to design the rates in this proceeding also be used in its next base rate case; (d) that the base summer cost of gas will be $0.3318 per therm and the base winter cost of gas will be $0.3846 per therm; (e) that a residential non-heating class be added with rates distinct from those applying to the residential heating class; and (f) that a discounted rate (with the discount set at 15%) be available to low income residential customers. In addition, parties to the settlement agreed to modify the methodology for calculating marginal costs to recognize that main extension costs are a component of marginal distribution capacity costs. The parties to the settlement did not agree on the proper method to calculate marginal production capacity costs or whether bad debts should be reflected in marginal commodity costs. However, they did agree to resolve those issues in Northern's C&LM proceeding, DR 92-048.

(b) Results of Embedded Studies

The Company also submitted an embedded cost study. The results of that study show all non-residential classes earning in excess of the total Company average. Those earnings range from a low of 5.56% for general heating customers to a high of 43.22% for air conditioning customers. In contrast, residential customers contributed a negative 0.26%

(c) Proposed Rates and Rate Structures

As noted above, the proposed rates were designed primarily on two ratemaking principles, namely cost reflection and rate continuity. Because of the need to avoid rate shock, the parties to the settlement initially agreed to move only one-fifth of the way to full marginal cost based rates. With the exception of the new residential non-heating class, this guideline limited class increases to 10%. After further refinements, the parties proposed increases of 5% for non-residential customers, 9.2% for residential heating customers and 10% for residential non-heating customers. Overall, the proposed rates will provide the Company with a 6.5% increase in revenues.

Staff witness McCluskey testified that the proposed class increases are based on the commission's class allocation decision in EnergyNorth Natural Gas, Inc., DR 90-183. The larger rate increases in this case can be explained by Northern's overall increase at 6.5% compared with only 1% for ENGI.

With respect to rate structure, the proposed rates introduce several new features including seasonally differentiated base gas and non-gas rates, fewer rate blocks, and a new extra large volume rate class. The Company has also committed to remove the minimum bill provision in the large volume rate schedule in its next base rate case. Rate levels were calculated based on weather normalized billing determinants.

(d) Extra Large Volume Rate Schedule

The results of the marginal cost study support the view that high load factor customers are less costly to serve than low load factor customers. Consistent with this result, the parties to the settlement recommend that a new firm rate schedule be offered, designed to attract customers that consume in excess of 1,000,000 therms per year and have winter usage less than 70 percent of annual usage.

(e) Salem Division Propane Customers

All except twenty-three customers in Northern's Salem Division have been converted from propane to natural gas and thus are billed based on Northern NH Division's tariffed rates. The Company proposed, and Staff agreed, to cancel the Salem Division tariff and bill the remaining propane customers on a hybrid rate comprising the non-gas component of the NH Division and a propane based gas cost. This change is expected to reduce the administrative burden on the Company.

III. Temporary Rate Refund

As noted above, the Staff and the Company do not agree on the calculation of the temporary rate refund. This dispute arose because the revenues that the Company receives from the proposed new XLV rate class are treated differently in temporary rates as compared to permanent rates.

Consistent with the Commission's temporary rate order, the Company placed into effect September 30, 1991, rates designed to recover an additional $1,900,000 annually: $1,561,532 from ratepayers served under existing rate schedules and $338,468 from a single new firm customer, Domtar Gypsum, Inc., served under the proposed XLV rate schedule. In contrast, the agreed permanent rate increase of $1,318,714 was determined without including the additional net revenues received from the sale of firm gas to Domtar. As a result, the Staff and the Company differ on whether the Domtar net revenues received during the temporary rate period should be included in the refund calculation and flowed through to ratepayers.

Positions of Staff and the Company

(a) Northern

Northern contends that its refund obligation should reflect the difference between: (a) the rates charged to existing firm customers during the temporary rate period and the rates that would have been charged to them under the permanent rate increase stipulated to in the settlement; and (b) the XLV rates charged to Domtar during the temporary rate period and the XLV rates ultimately approved by the Commission.

In support of its position, Northern makes the following arguments. First, Staff's calculation produces an illogical and erroneous result. Rather than collecting the agreed upon $1,318,714 from existing firm ratepayers during the temporary rate period, Northern would only be entitled to approximately $980,000 from those customers, i.e., the agreed permanent increase less the projected Domtar net revenues.

Second, Northern argues that while its firm ratepayers did not benefit from interruptible margins during the temporary rate period, they "did benefit from the inclusion of Domtar as a firm customer because the $1.9 million temporary rate increase, which otherwise would have been borne completely by existing firm customers, was also portioned to Domtar, thus reducing the amount of the temporary rate increase for all firm customers by over $330,000". (page 12, Initial Brief)

Third, in its reply brief, Northern argues that as a result of Staff's refund calculation, the agreed permanent rate increase takes effect prospectively instead of retroactively. This, it argues, is contrary to both the agreement of the parties and the statutory ratemaking framework. Northern concludes that as a matter of law, the Commission must apply any approved increase both to the temporary rate period and prospectively.

(b) Staff

Staff's basic position is that the refund amount should reflect the difference between the net revenues actually received during the temporary rate period and the net revenues that would have been received had rates based on the agreed permanent increase been in effect. Since the former includes the net revenues received from the sale of gas to Domtar, Staff contends that those revenues should be incorporated in the refund calculation. The facts relating to this issue are: (a) Domtar has received continuous service from Northern since the beginning of the test year and thus cannot be regarded as a new customer; (b) all net revenues received from the sale of gas to Domtar prior to the effective date of temporary rates were flowed through to ratepayers; and (c) there was no agreement between Staff and the Company that would enable the latter to recover more than the agreed permanent rate increase during the temporary rate period. Based on these facts, Staff contends that equity requires that any Domtar net revenues generated during the temporary rate period be directed to ratepayers.

Staff's position is based on four arguments. First, Staff believes its concession in settlement to exclude the Domtar net revenues from the determination of permanent rate increase (worth $368,833 to Northern) should not be added to by arbitrarily lowering the Company's refund obligation.

Second, Staff urges the commission to reject the Company's argument that the exclusion of the Domtar net revenues from the determination of permanent rate increase was justified on the grounds that non-revenue producing investments made after the test year were excluded from rate base. Staff contends that the issue of non-revenue producing investments is unrelated to the refund calculation and, moreover, their exclusion from rate base is entirely consistent with the commission's previous decisions. Further, the settlement agreement provides for full recovery of those investments through a step adjustment to base rates effective November 1, 1992.

Third, Staff contends that ratepayers and not stockholders should benefit from the Domtar net revenues received during the temporary rate period because they alone bear the costs and expenses incurred in the provision of that service. In particular, Staff notes that all of the costs and expenses that were incurred in serving Domtar during the test year are included in the cost of service and thus will be recovered through the rates charged to existing ratepayers.

Finally, Staff recommends that the commission disregard arguments that alleged investments by Northern to provide Domtar with interruptible service have not contributed to the Company's earnings. Relative to this position, Staff puts forward two arguments. First, with the exception of the service and meter, there is no evidence in the record to support the claim that investments were actually made. Secondly, even if investments were made, the 1989 agreement that Northern reached with the Staff and the Office of the Consumer Advocate requires that Domtar be assessed a capital contribution to recover all distribution system investments directly incurred in providing interruptible service. Thus, Staff argues, if the Company omitted to levy such capital contribution, its earnings difficulties rest on its own shoulders.

III. Commission Analysis

(a) Cost of Capital

Although the Company takes the position that it concurs only with the total stipulated permanent increase, and not with the components that support that increase, the commission must authorize a specific rate of return, if only for the purpose of measuring future performance. After reviewing the testimony of Coleman and Moul, we find that the 10.01% cost of capital included in Attachment 1 to the agreement is in line with returns recently authorized for other utilities.

(b) Revenue Deficiency

Staff witness Sullivan testified that in negotiating the recommended permanent rate increase, he agreed to exclude the Domtar profit from the revenue deficiency calculation. Had that profit been included, the permanent increase would have been only $949,881. In its brief, Staff defends the concession on the basis of its understanding that certain investments were made <u>after</u> the test year, and were thus excluded from rate base. Based on this explanation, the concession appears reasonable. However, the Company, in its initial brief, admits that the investments in question (i.e., $269,242) were made <u>during</u> the test year. In light of this information, plus the fact that the costs and expenses of serving Domtar during the test year are included in the cost of service, the decision to make the concession appears less sound. Nonetheless, we accept the exclusion in recognition of the fact that the agreement resulted from numerous concessions by both parties and will allow the recommended permanent rate increase to take effect.

(c) Weather Normalization

In EnergyNorth Natural Gas, Inc., DR 90-183, we rejected the confidence interval approach to weather normalization and adopted instead the so-called "Northern Method." Both the Company and the

Staff used that method in this proceeding. The agreed permanent rate increase reflects the Staff's application of that method, an application that differs from the Company's only with respect to the sample size used to determine the mean or "normal" degree days. To further standardize the weather normalization methodology, we will require all companies to employ a 30 year sample size to compute the monthly mean degree days. The submission of additional alternate weather adjustments based on different sample sizes shall be accompanied by a showing that the 30 year sample unreasonably biases the result.

(d) Rate Design

We find the proposed rate class increases consistent with our decision in ENGI, DR 90-183 and thus a reasonable starting point for the rate design process. We also agree with witnesses Simpson and McCluskey that the rate design structures are similar to the structures that we approved for ENGI.

(e) Temporary Rate Refund

With respect to the contested issue of the temporary rate refund, our analysis leads us to the conclusion that Northern's arguments lack an element of fairness. We were particularly struck by the omission of a sound equitable argument as to why stockholders, and not ratepayers, should receive the benefit of Domtar net revenues. Perhaps this omission is due to the fact that prior to the implementation of temporary rates, all net revenues generated from interruptible service to Domtar were flowed through to ratepayers, and effective November 1, 1992, all net revenues generated from the provision of firm service flow through to ratepayers. More importantly perhaps is the fact that the cost of service on which the proposed permanent rates are based, and thus recovered only from existing ratepayers, includes costs and expenses attributable to Domtar. Even the $269,242 investment to provide Domtar with firm service, that was removed from rate base, will be reinstated in full come the first step adjustment.

We also believe that Staff more than adequately rebutted the Company's argument relating to its failure to earn on its Domtar interruptible investments. As for the exclusion from rate base of its non-revenue producing investments, we agree with Staff that the issue is only weakly related to the refund but disagree with the implication that the Company is fully compensated by the step adjustment. Clearly, the Company forgoes the carrying charges on those investments as long as they are excluded from rates. Nonetheless, their exclusion is consistent with previous decisions of this commission.

We also reject the assertion that existing ratepayers benefit during the temporary rate period. While it is true that the rates charged to those customers during that period reflected an increase of only $1,561,532 and not the full $1,900,000, we do not consider this a benefit. Using the Company's refund calculation and the approved temporary rates, Northern's refund obligation would be $242,818 (see table below). If we had not authorized firm service to Domtar, and as a result existing ratepayers bore the full $1,900,000 temporary rate increase, the refund obligation rises to $581,286, again based on Northern's calculation. Clearly then, under both scenarios, existing ratepayers pay the agreed permanent increase of $1,318,714 and thus would receive no benefit from the provision of service to Domtar.

	Temporary Rate Refund	
	With Domtar	Without
1. Temporary Increase	$1,900,000	$1,900,000
2. Apportioned to Ratepayers	$1,561,532	$1,900,000
3. Apportioned to Domtar	$338,468	$0
4. Permanent Increase	$1,318,714	$1,318,714
5. Refund (2 minus 4)	$242,818	$581,286
6. Net Increase (2 minus 5)	$1,318,714	$1,318,714

Finally, we address Northern's argument that the agreed rate increase must be given effect at the start of the temporary rate period, not prospectively. In essence, the Company believes that if the Domtar net revenues are flowed through to ratepayers, Northern would not receive the full benefit of the agreed permanent rate increase until the end of the temporary rate period. This, according to Northern, is contrary to the settlement agreement and the statutory ratemaking framework. We disagree. While the Company is correct that Staff's refund calculation would only allow for the recovery of an additional $980,246 annually from existing ratepayers during the temporary rate period, that figure assumes Northern received and retained $338,468 from Domtar during that period. Combining the two amounts we find that the Company does not, as claimed, collect less during the temporary rate period than was agreed. Thus, Staff's refund position is consistent with the Commission's statutory responsibility to provide the Company an opportunity to earn the rate of return assumed in the agreed rate increase. In our view, the Company's position would provide an opportunity to earn in excess of that level.

This brings us to the period after temporary rates and before the step adjustment. As we see it, the Domtar net revenues retained during that period are more than offset by the carrying charges that the Company forgoes on non-revenue producing investments made after the test year and therefore we do not find the settlement unreasonable.

Based on the above analysis, we will adopt Staff's calculation of the refund.

Our order will issue accordingly.

Concurring:
July 21, 1992

Douglas L. Patch	Bruce B. Ellsworth	Linda G. Stevens
Chairman	Commissioner	Commissioner

DR 91-081

NORTHERN UTILITIES, INC.

Order Accepting the Settlement Agreement and Adopting a Method to Calculate the Temporary Rate Refund.

O R D E R N O. 20,546

Upon consideration of the foregoing report, which is made a part hereof; it is hereby

ORDERED, that the settlement agreement be and hereby is approved; and it is

FURTHER ORDERED, that staff's method to calculate the temporary rate refund as described in Attachment 6 to the settlement agreement be adopted.

By order of the New Hampshire Public Utilities Commission this twenty-first day of July, 1992.

Douglas L. Patch Chairman	Bruce B. Ellsworth Commissioner	Linda G. Stevens Commissioner

Attested by:

Wynn E. Arnold
Executive Director & Secretary

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2004-813

April 11, 2005

MAINE PUBLIC UTILITIES COMMISSION
Investigation Into Maintenance and Replacement Program for Northern Utilities, Inc.'s Cast Iron Facilities

ORDER APPROVING STIPULATION

Welch, Chairman; Diamond and Reishus, Commissioners

I. SUMMARY

We approve a stipulation under which Northern Utilities, Inc. (Northern) will replace its cast iron facilities in Lewiston and Auburn by December 1, 2008. On January 1, 2008, Northern will propose how to replace the remaining cast iron facilities in Portland and Westbrook based on its experience in Lewiston/Auburn.

II. PROCEDURAL HISTORY

On December 14, 2004, the Commission opened an investigation into the maintenance and replacement of the cast iron mains and services in Northern's underground distribution system in Maine. *See* Notice of Investigation, Dec. 14, 2004 at 2.[1] The Office of Public Advocate (OPA) intervened in this proceeding.

Also in December, Northern filed the prefiled testimony of Stephen Bryant, Northern's President, and Danny Cote, Northern's General Manager, stating the Company's views on an adequate cast iron replacement program, whether it could evaluate the extent of graphitization in its system, and how it might achieve accelerated replacement of cast iron facilities in 10 years. Northern's 10-year plan called for replacing all the cast iron facilities in Lewiston/Auburn during the first four years and then replacing the Portland/Westbrook pipe in the subsequent six years. Northern maintained that no accelerated program was necessary to protect or to promote public safety, but that if the Commission determined an accelerated replacement was required, a 10-year replacement would be the most cost-effective, administratively efficient, and operationally sound method.

Following the first technical conference, the OPA filed the testimony of Michael McGarry, Sr., Rudolph Krizan, P.E., and Howard Solganick, P.E. of Blueridge Consulting in

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[1] Cast iron pipes were typically installed prior to the 1960's for use in manufactured gas distribution systems. These systems were later converted for use in distribution of natural gas. Cast iron is susceptible to breakage from ground subsidence or movement which may occur during freeze-thaw cycles or other events such as construction or earthquakes.

support of its position that Northern's current "opportunistic" approach to cast iron replacement, coupled with its leak detection practices, is consistent with industry practice and therefore could be considered adequate to promote public safety and protect against a serious incident involving Northern's low pressure cast iron mains. In addition, the OPA expressed concern that the incremental costs of an accelerated cast iron replacement program might not represent a socially optimal use of public resources devoted to public safety, as compared to other expenditures, and therefore might not be acceptable to Northern's ratepayers.

On March 2, 2005, the Staff issued a Bench Analysis recommending adoption of a 10-year accelerated replacement program for all cast iron facilities in Northern's system. During this proceeding, the participants engaged in multiple rounds of discovery and technical conferences on Northern's and OPA's testimony and on Staff's Bench Analysis.

On March 17, 2005, Northern filed a Stipulation (attached and incorporated with this Order), executed with the Office of the Public Advocate (OPA), proposing a resolution of the issues in this proceeding. On March 22, 2005, the Commission held a hearing on the Stipulation attended by Steve Bryant, President, and Dan Cote, Vice President of Operations, for Northern and by Michael McGarry for the OPA.

II. DESCRIPTION OF STIPULATION

The Stipulation states that Northern will replace all cast iron mains and services in Lewiston and Auburn during the period from April 1, 2005 to December 1, 2008. Whenever possible, this will be achieved by inserting plastic main into existing cast iron mains. This method is expected to result in lower costs than would full-scale excavation. Northern will use competitive bidding and prudent, cost-effective practices in this project. While engaged in this project, Northern will continue to replace cast iron facilities using its "opportunistic" approach and when cast iron main segments exceed the replacement threshold on the Cast Iron Main Assessment Model developed in consultation with the Commission's Gas Safety Inspector in Docket No. 2000-322. Under Northern's "opportunistic" replacement program, mains and services are replaced in conjunction with all state and municipal road improvement projects when there is an economic advantage to doing so or when construction in proximity to Northern's facilities may jeopardize the integrity of its facilities.

In addition, the Stipulation establishes that Northern may seek cost recovery in rates during its next base rate case and may propose a rate recovery mechanism for successive years of this project. At the time of the rate case, Northern agrees to file a proposed alternative rate-making mechanism but may take any position with regard to the desirability of such a mechanism. In considering the alternative ratemaking mechanism, parties will be free to propose inclusion of appropriate revenue adjustments such as incremental investment costs, depreciation, property taxes, productivity offsets and operational savings due to the accelerated program or other causes.

On January 1, 2008, Northern will file a plan for cast iron replacement in Portland and Westbrook. The parties to the stipulation anticipate that the Portland/Westbrook plan will employ lessons learned from the Lewiston/Auburn project. All parties are free to put forth their views on what form of replacement plan should be approved for Portland and Westbrook.

IV. DISCUSSION

In considering whether to approve a stipulation, we must determine whether the stipulated result is in the public interest. We also determine whether a broad spectrum of interests were involved in arriving at the settlement and whether the settlement process was fair. The parties in this proceeding, Northern and the Public Advocate, cover a sufficiently broad spectrum of interests in this context. There are no other parties and no opposing interests in this particular case. The parties worked in consultation with Staff, including our Gas Safety Inspector, to develop the proposed resolution without indication of unfairness in the settlement process. We now turn to the question of whether the stipulated result serves the public interest.

Throughout this proceeding, Northern has maintained that accelerated replacement of its cast iron facilities is not necessary to ensure public safety, given its diligent leak monitoring and operational practices. However, if allowed adequate rate recovery, it would replace its cast iron facilities on an accelerated schedule. Northern asserts that the optimal time frame for accelerated replacement of all its cast iron facilities in Lewiston, Auburn, Portland, and Westbrook is 10 years because this allows it to take advantage of construction economies yet avoids placing undue burdens on the municipalities in which it is working. Northern's replacement of its cast iron facilities, using insertion of plastic pipe where possible, will result in lower costs than excavation, largely due to savings in road reclamation costs. Northern proposes to begin replacement in Lewiston/Auburn because of its belief that the area's typical frost levels and the frequency of its freeze-thaw cycles tend toward greater incidence of soil disruption and, therefore, cast iron main breaks, than in the Portland and Westbrook areas.

OPA initially opposed an accelerated replacement of Northern's cast iron facilities. OPA argues that the costs of doing so were disproportionate to the increased public safety, especially when compared to other risks in society. OPA opposed incurring the incremental cost of a 10-year replacement program, estimated to be $278 per customer, and preferred and approach closer to the "opportunistic" replacement program, which Northern estimated would take 43 years to complete.

The Commission's Gas Safety Inspector supported a comprehensive 10-year replacement program based on the safety gains that would be achieved as demonstrated by statistical evidence provided in the American Gas Foundation Report using historical numbers and causes of distribution system failures in the nation and the northeast region.

Under the Stipulation, Northern will proceed with accelerated replacement in Lewiston and Auburn during the next four years, and Northern's experience with that effort will inform its proposal for addressing cast iron facilities replacement in Portland and Westbrook. In January 2008, we, along with the parties, will consider the information gained from the Lewiston and Auburn replacement program so that we may determine how Northern should proceed in the remaining municipalities in which cast iron facilities are located. In the meantime, Northern will continue in all municipalities with its current level of replacement under its "opportunistic" program and as indicated by the rankings of segments under the Cast Iron Main Assessment Model.

We find the Stipulation reasonable and consistent with the public interest. Both the term and the location of initial replacement are consistent with Northern's 10-year plan. Given that Northern has not undertaken main replacement on this scale or accelerated time frame before, it makes sense for Northern and the parties to review its experience with this initial phase, including operational issues and rate impacts, before we determine how to proceed with the remaining municipalities. Finally, the estimated costs of this program, while greater for the first 15 years, appear reasonable overall with significant savings after year 15. The greatest annual rate impact ($2.1 million) is expected to occur in 2008, resulting in a likely rate effect of 3%.[2]

We note the concern expressed by our Gas Safety Inspector that the risk of cast iron incidents exists also in Portland and Westbrook and, from a safety perspective, must also be addressed. We do not read this Stipulation to suggest that the accelerated replacement of cast iron facilities should end with Lewiston/Auburn. Indeed, while we do not resolve how we will proceed after 2008 now, we believe that accelerating the replacement of cast iron -- as the Stipulation will achieve in a significant (and perhaps most vulnerable) part of Northern's territory – is fully supported by the record in this case. We expect, therefore, though we do not decide, that a party suggesting a return to the current "opportunistic" approach (or some other deceleration relative to the initial phase) would have to provide persuasive evidence that to do so would be in the public interest.

For these reasons, we find that this Stipulation does serve the public interest and approve it.

Dated at Augusta, Maine, this 11th day of April, 2005.

BY ORDER OF THE COMMISSION

____
Dennis L. Keschl
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Diamond
Reishus

[2] For the 10-year plan, the greatest annual rate impact, about 10% ($6 million), would likely occur in year 10.

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S.A. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 1004 of the Commission's Rules of Practice and Procedure (65-407 C.M.R.110) within 20 days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within **21 days** of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S.A. § 1320(1)-(4) and the Maine Rules of Appellate Procedure.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S.A. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

DOCKET NO. 2004-813

NORTHERN UTILITIES, INC.
Cast Iron Replacement Program

STIPULATION

Northern Utilities, Inc. – Maine ("Northern") and the Office of Public Advocate ("OPA") hereby agree and stipulate as follows:

I. PURPOSE

The purpose of this stipulation is to settle all issues raised in Docket No. 2004-813, to avoid a hearing on the issues raised in that docket, and to expedite the Public Utilities Commission's ("Commission's") consideration and resolution of this proceeding. The provisions agreed to herein have been reached as a result of information initially filed in this proceeding, gathered through discovery, technical sessions conducted at the Commission and from discussions between the parties in this case.

II. PROCEDURAL HISTORY

On December 14, 2004, the Public Utilities Commission ("Commission") instituted an investigation ("Order") into the reasonable maintenance and replacement of the cast iron mains and services located in Northern Utilities, Inc.'s ("Northern's") underground distribution system in Maine. The proceeding was docketed Docket No. 2004-813. Both Northern and the Office of Public Advocate ("OPA") ("the Parties") are active participants in this proceeding.

In its Order opening investigation, the Commission sought Northern's views on an adequate cast iron replacement program, whether it could evaluate the extent of graphitization in its system, and how a plan for accelerated replacement of cast iron facilities in 10 years might be achieved.

Northern responded with written comments and the prefiled testimony of Stephen Bryant, Northern's President, and Danny Cote, Northern's General Manager, supporting those comments. Exhibit Northern-1; Exhibit Northern-2. Northern's comments and testimony posited that no accelerated program was necessary to protect or to promote public safety, but that if the Commission determined an accelerated replacement was required, a ten (10) year replacement would be the most cost-effective, administratively efficient, and operationally sound method.

Following the first technical conference, the OPA filed the testimony of Michael McGarry of Blueridge Consulting in support of its position that Northern's current "opportunistic" approach to cast iron replacement, coupled with its leak detection practices, is adequate to promote and protect public safety resulting from a serious incident involving the Company's low pressure cast iron main systems. Moreover, the OPA expressed concern that the incremental costs of an accelerated cast iron replacement program might not represent an optimal use of public resources devoted to public safety and therefore might not be acceptable to Northern's ratepayers.

Discovery was exchanged and an additional technical conference was held at the Commission, before the Commission Staff issued its Bench Analysis. The Bench Analysis was issued on March 2, 2005.

III. RECOMMENDED APPROVALS AND FINDINGS

Based on the record in this case, the parties to this Stipulation agree and recommend that the Commission conclude these proceedings by issuing an order that approves, accepts and adopts this Stipulation, including the following provisions:

1. Northern will replace, by the "insertion" method to the extent possible, using prudent, cost-effective operations techniques and competitive bidding, all cast iron mains and services in the cities of Lewiston and Auburn during the period April 1, 2005 to December 1, 2008 ("Lewiston/Auburn CI Replacement Project").

2. Northern and the OPA will return to the Commission and describe the reasons for any extension that may be needed to finalize and complete the Lewiston/Auburn CI Replacement Project.

3. Northern will continue with the "opportunistic program" in all municipalities during the period of the Lewiston/Auburn CI Replacement Project.

    a. The phrase "opportunistic program" means that Northern will replace cast iron and bare steel mains, bare steel services and associated appurtenances connected to these mains and services in conjunction with all state and municipal road improvement projects when there is an economic advantage to do so or when construction in proximity to Northern's facilities may jeopardize the integrity of the cast iron or bare steel facilities.

4. In addition to the "opportunistic program," Northern will replace, in any municipality, those cast iron segments that exceed the replacement threshold on the Cast Iron Main Assessment Model developed in consultation with the Commission's Gas Safety Director. Northern may seek a waiver from the Commission if it believes there is good cause for an extension of time to replace any segments that are ranked for replacement.

5. Northern may seek cost recovery for the incremental investment associated with the Lewiston/Auburn CI Replacement Project as follows:

a. Northern will file a base rate case prior to the introduction of any step adjustment or other rate recovery mechanism;

b. Northern's base rate request shall include a proposal for an alternative rate-making mechanism as provided in 35-A M.R.S.A. §4706. Northern and OPA will maintain the right to take any position regarding the desirability of the Commission's approval of that mechanism or any alternative rate-making mechanism offered by other parties.

c. Northern's base rate filing will include all investments made under the Accelerated Replacement Program through the test year of the base rate case;

d. Negotiations regarding the elements of an alternative rate-making mechanism (whether proposed by Northern, the OPA or any other party during the pendency of the base rate proceeding) will be conducted in good faith;

e. In the context of an alternative rate-making mechanism under 35-A M.R.S.A. §4706, the OPA will not object to consideration of an annual rate adjustment designed to provide Northern an opportunity to earn a reasonable return on its investments and to recover related costs, such as depreciation and property taxes, to reflect incremental investments that result from accelerated replacement of cast-iron mains. This rate-making mechanism will also reflect any appropriate offsets, including, but not limited to, productivity offsets and operational expense savings that can be determined to result from the accelerated program.

f. The OPA and Northern are free to take the position that other items should be considered as part of any annual cost recovery for incremental investments.

6. On January 1, 2008, Northern agrees to file its plan for cast iron replacement plan for Portland and Westbrook ("Portland CI Replacement Plan"), in which recommendations relative to financial, operational and engineering aspects of any proposed replacement will be presented. It is anticipated that the Portland CI Replacement plan will benefit from and utilize the techniques and experience gained from the Lewiston/Auburn CI Replacement Program. Northern, OPA, and any other party will be free to recommend continuation of Northern's current "opportunistic" replacement program in Portland and Westbrook, or some form of an accelerated replacement program.

IV. STIPULATIONS AS TO PROCEDURE

1. Staff Presentation of Stipulation. The parties to this Stipulation waive any rights they may have under 5 M.R.S.A. sec. 9062(4) and Section 742 of the Commission Rules of Practice and Procedure to the extent necessary to permit Staff to discuss this stipulation and the resolution of this matter with the Commissioners at the Commission's scheduled deliberations, without providing to the parties an Examiner's Report or the opportunity to file Exceptions.

2. Record. The record on which the parties enter into this Stipulation and on which the Commission may base its decision whether to accept and approve this Stipulation shall consist of (1) this Stipulation; (2) the prefiled testimony of Stephen H. Bryant; (3) the prefiled testimony of Danny Cote; (4) the pre-filed panel testimony of Blue Ridge Consulting on behalf of the OPA (5) the prefiled supplemental testimony of Michael J. McGarry, Sr; (6) Northern's response to written advisory data requests, formal and informal, issued by Staff; (7) Northern's response to oral data requests issued by Staff at the Technical Conferences; (8) Northern's responses to written data requests of the OPA; (9) Northern's responses to oral data requests issued by the OPA at the Technical Conferences; (10) OPA's responses to written advisory data requests, formal and informal, issued by Staff; (11) OPA's responses to oral data requests issued by Staff at Technical Conferences; (12) OPA's responses to written data requests issued by Northern; (13) the Bench Analysis provided by Staff; (14) the transcript of the Technical Conferences; and (15) any other material furnished by the Staff to the Commission, either orally or in writing, to assist the Commission in deciding whether to accept and approve this Stipulation.

3. Non-Precedential Effect. This Stipulation shall not be considered legal precedent, nor shall it preclude a party from making any contention or exercising any rights, including the right of appeal, in any future Commission investigation or proceeding or any other trial or action.

4. Stipulation as an Integrated Document/ Void if Rejected. This Stipulation represents the full agreement between the parties to the Stipulation and rejection of any part of this Stipulation constitutes a rejection of the whole. If not accepted by the Commission according

to its terms, this Stipulation shall be void and of no further force and effect.

Respectfully submitted this __ day of March, 2005.

Office of Public Advocate
Stephen Ward, Public Advocate

By:______________________________

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Northern Utilities, Inc. – Maine

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